Attachment 4

Stationary Source NOx Control Program

Overview

NR428 addresses stationary source NOx emissions and is structured to meet Rate-of-Progress (ROP) emission reduction requirements through 2007, the ozone attainment deadline for the Lake Michigan region. The program encompasses the eight southeast WI counties and proposes NOx controls for larger existing sources and establishes emission standards for new sources. The existing source control program reduces emissions at electric utility facilities and on larger industrial combustion sources from projected baseline levels in 2002 through 2007. The performance standards for new sources address emission rates from new uncontrolled facilities in the eight counties and for those undergoing major modification.

Performance Standards for Existing Sources

The existing source performance standards are projected to effect 48 individual units at 21 facilities. **Figure 4-1** notes the facilities and their relative location. This program is targeted to achieve 30 tons NOx per day at an average cost of approximately $1,000 per day by the 2003 ozone season. The program is expected to achieve a 55 ton per day reduction by 2007 at an average cost of approximately $1,600 per ton. **Table 4-1** details the estimated program cost and impact for existing sources. The program consists of two basic elements: 1) ozone season emission limits for electric utility systems comprised of boilers equal to or greater than 500 mmbtu/hr; and 2) Unit-specific requirements of either emission rate limits or combustion optimization for other large emission sources. **Table 4-7** summarizes the performance standards by categories of combustion equipment and the associated applicability threshold.

Electric Utility System Emission Limits

Utility system emission limits are proposed for all utility boilers equal to or greater than 500 mmbtu/hr and are effective December 31, 2002. The limits were developed to meet the bulk of ROP requirements for each year through 2007 (specified in **Table 4-7**), and account for all the ROP need not met by the other plan components. The emission limits apply during each respective ozone season and require determination of a 30 day rolling average over all designated units in a utility system based on 40 CFR Part 75 monitoring. A total of seventeen units, in the Alliant and WEPCO utility systems, are affected under this provision and are expected to pursue a combination of combustion modifications and post-combustion control for compliance. The list of effected utility sources and assumed controls are listed in **Table 4-5**. Currently, the utility units have the necessary Part 75 monitoring and can therefore meet the monitoring requirements of the rule.

The majority of NOx reductions are targeted from the electric utility sector for several reasons. First, the utility boilers (=> 500 mmbtu/hr) account for roughly 90% or 147 ton/day of the total NOx emissions from stationary source categories. Second, by designating all of a utility's major generation units into one averaging category, the rule provides the greatest flexibility in meeting reduction requirements. And third, the EPA determined, in their analysis for reducing NOx transport (the NOx SIP Call), that control of large utility systems to a 0.15 lbs/mmbtu emission rate costs less than $2,000 per ton on a system average basis. EPA determined the 0.15 average control level to be "highly cost effective". Hence the utility system focus serves to obtain NOx reductions in a cost-effective manner while providing flexibility to the affected sources.

Table 4-1 Summary of the Impact of Performance Standards for Existing Sources

Program Element	No. of Facilities	No. of Units	Units Currently Meeting NR 428	2002 NOx Reduction (tpd)	Estimated Annual Cost ($/year)	Estimated Annual Cost ($/ton)
Utility System in 2002	5	17	0	25	up to 8 $M	1,000
Utility System in 2007	5	17	0	48	up to 13.4 $M	1,600
Unit Specific Emission Limits	8	15	6	2.3	(80,000) to 70,000	-250 to 200
NOx Combustion Optimization	10	16	0	2.3	(35,000) to 18,000	-100 to 50
Subtotal	**17**	**31**	**6**	**4.6**	**(123,190) to 88,000**	**-200 to 150**
Program Total – 2002	**21**	**48**	**6**	**29.6**	**up to 8.1 $M**	**~ 1,000**
Program Total – 2007	**21**	**48**	**6**	**54.6**	**up to 13.5 $M**	**~1,600**

The initial requirement is for the utilities to meet an 0.33 lbs/mmbtu emission rate by the 2003 ozone season. An analysis of control options in **Table 4-2** indicates this rate may potentially be reached through combustion modifications of Over-Fire Air (OFA) at the Alliant facility and through the installation of Low NOx burners at several WEPCO facilities. WEPCO may also have to utilize a higher cost natural gas re-burn system at the Pleasant Prairie facility during the initial 2003 ozone season. However, to achieve system average emission rates below this level, the analysis shows that the utilities would likely have to implement additional post-combustion controls. Although post-combustion controls are cost effective and may be implemented to comply with the final 2007 emission rate, the engineering and construction timing of these controls (such as SCR) would make implementation by the 2003 ozone season extremely difficult. That could result in significant cost increases for the needed system reductions. The control phase-in approach starting at the 0.33 emission limit allows the utility systems to first optimize around combustion modification if that is the most efficient path to NOx reduction.

Table 4-2 Analysis of Electric Utility System Controls

Utility	Emission Rate	Anticipated NOx Control Installations	Estimated Annual Cost (M$)	Estimated Cost per Ton ($/ton)
Alliant – Edgewater	0.33 to 0.34	2 OFA	< 1.6 M	400
	0.31 to 0.32	2 OFA + 1 SNCR	< 2.4 M	600
	< 0.31	2 OFA + 1 SCR	up to 7 M	2,100
WEPCO	0.33 to 0.34	3 LNB + FLGR	up to 4 M	1,000
	0.31 to 0.33	2 LNB + One SCR (or 2 additional LNB@ PP w/ additional LNB installations @ other units)	up to 6.5 M	1,300
2002 ROP	0.33		up to 6 M	950
2007 ROP	0.28		up to 13.5 M	1,600

OFA – Overfire Air is a combustion modification which provides air above the main combustion area to allow for low NOx staged firing in the chamber. This technology provides 60 to 70% reduction in cyclone boilers.
SNCR –Selective non-catalytic reduction is a post-combustion technique which involves the addition of ammonia or urea into exhaust gases to convert NOx to N_2.
SCR – Selective catalytic reduction is a post-combustion technique which involves installation of a large catalyst bed and the injection of ammonia or urea to achieve greater NOx control levels than either OFA or SNCR.
FLGR – Fuel Lean Gas Reburn is a staged combustion system with the potential addition of urea or amine for deep reductions.

Unit Specific Performance Standards

The rule proposes emission limits for individual existing NOx emission units to be met during the ozone season effective December 31, 2002. These are listed in **Table 4-7**. The limits are specified by source category and fuel type to reflect low NOx combustion technology. Applicability is based on the unit's maximum capacity combined with consideration of its ozone season utilization based on 2000 ozone season or after. Units not initially subject to the limits can trigger the requirement in a later year based on growing utilization. The unit is required to monitor emissions using 40CFR Part 60 monitoring or equivalent and show compliance with the emission rate on a 30 day rolling average and is required to submit compliance information along with current annual reports.

The emission limits were determined based on an analysis of combustion control modifications and low NOx technology. This primarily reflects low NOx burners for gas and oil fired processes and low NOx burners or air staging of the combustion process for solid fueled boilers. These technologies reduce NOx by controlling excess air to the combustion process and in many of the newer applications have demonstrated the potential to increase fuel efficiency. Because fuel consumption in larger industrial applications is typically a big portion of annual facility operating cost, these improved fuel combustion technologies can result in significant operational savings. It is also expected that the continuous monitoring of the rule will yield additional fuel efficiency gains. The capacity thresholds and utilization factors for each source category reflects level at which potential savings offset the expected initial capital investment. Units not utilized on a frequent basis would not see significant operational savings.

Based on historic data, the proposed emission limits for existing sources affect fifteen units at eight facilities for an approximate total reduction potential of 4.6 tons per day. These are listed in

Table 4-6. An analysis of controls for these sources resulted in an average program cost ranging from a net savings of $250/ton including efficiency improvements to a direct cost of $200/ton excluding the efficiency gains. Because final rule applicability is based on a unit's record of operation in 2000 or after, the list of affected source is subject to change. The rule requires any unit triggering the utilization threshold to demonstrate compliance with the appropriate limit by the following calendar year.

Combustion Optimization for NOx Emissions -

The combustion optimization procedure applies to individual units as specified by source category in **Table 4-7**. The applicability is generally based on units with a 75 mmbtu/hr or greater capacity and a 20% or greater ozone season utilization factor. The rule provides that sources with an emission limit performance standard are exempt from the optimization requirement. As with the emission limits, the optimization requirement has a compliance date of December 31, 2002 and is shown to be applicable based on the year 2000 ozone season capacity utilization level. Units triggering the utilization threshold after 2000 must show compliance with the optimization requirement the following calendar year.

Combustion optimization requires the operator to pursue an engineering evaluation of the combustion unit and air delivery system to identify options for reduction of NOx emissions based on operational improvements. The facility then uses this information to determine a combustion optimization plan pursuant to review by the Department.

The unit is then set for optimized operation according to the plan and monitored to determine a low NOx operating curve over the potential load swing of the unit. Although low NOx combustion equipment modifications are a component of the evaluation, the source is only required to optimize existing equipment, but may elect to pursue these alternatives. The unit is ultimately required to operate consistent with the determination of an optimum combustion approach. A continuous combustion analyzer system is to be used to ensure continued operation with the low-NOx curve.

For simple combustion units, the initial optimization procedure may consist of a modest tuning effort combined with a balancing of the combustion airflow. The more complex combustion units subject to the rule, such as coal fired stoker boilers, will require a more in-depth evaluation of potential combustion modifications and process adjustments. These complex evaluations are expected to incur an initial capital cost per unit approaching $50,000. The continuous monitoring systems are expected to have an initial capital cost of $10,000 to $15,000. As with other low-NOx combustion technologies, the primary mechanism for emission reduction is through the control of excess combustion air and is expected to result in fuel efficiency gains. The unit threshold and capacity utilization are based on the threshold for the fuel and cost savings to offset initial capital investments for the optimization process.

Based on historic data, 16 units at 10 facilities are potentially subject to the optimization requirement. These are as listed in **Table 4-6**. The optimization component is anticipated to yield 2.3 tons per day in NOx reduction for ROP starting in 2002 (for the 2003 ozone season).

Based on the anticipated efficiency gains, these facilities can expect to save upwards of $100/ton NOx reduction. Excluding the projected efficiency gains (as an indirect savings) related to the NOx reduction, the direct NOx control expenditure is estimated to range upwards to $50/ton.

Performance Standards for New Sources

New sources shall meet an annual emission limit based on source category and fuel type. These are listed in **Table 4-8**. The criteria for "New" is met by any unit obtaining a new source construction permit or for an existing unit which undergoes a "major modification" as defined by the current New Source Review programs. Compliance with the emission limits is based on a 30 day rolling average using 40 CFR Part 60 monitoring or equivalent, however, the rule provides the ability to demonstrate alternative monitoring as appropriate to each source. A compliance report is submitted annually as part of other reporting elements specified in the source's operation permit.

The new source limit standards require sources to implement readily available low-NOx technology for new equipment. The limits are based on combustion technology specific to primary fuel type. The limits do not require post-combustion control investments. This ensures a minimum addition of NOx emissions from new sources in a cost-effective manner. Because the limits are based on control technology integrated into the combustion equipment, applicability is based exclusively on unit capacity thresholds.

Table 4-3 Analysis of 1999 Permits in 8 Proposed Counties

Source Type	# of Units	Capacity Range
Gas/Oil Boilers	3	< 25 mmbtu/hr
IC Engines	9	150 mmbtu/hr
Asphalt Plants	2	150 mmbtu/hr
Furnaces	3	< 25 mmbtu/hr
Gas Fired Processes	3	< 25 mmbtu/hr
Estimated Total NOx ~ 1 ton per day		

The new source standards have the potential to significantly reduce daily NOx emissions. As shown in **Table 4-3**, an analysis of 1999 permits indicate that new and modified sources not addressed by the New Source Programs had the potential to add up to 1 ton per day of NOx during the ozone season. In addition, **Table 4-4** shows several other potential new NOx emission sources not captured in the 1999 analysis which would or could be expected to become operational during course of the ROP plan. The analysis shows that one typical source alone can account for up to 0.5 tpd NOx and indicates that the total potential to emit from new sources in one year could easily exceed the one ton per day estimated for 1999. **Table 4-4** illustrates that the limits have the potential to reduce new source emission levels from 45 to 75%.

Table 4-4 Analysis of Typical New Sources not Captured by the NSR or PSD programs.

Typical Source	Large Sources not Captured by NSR	Uncontrolled Emission Rate (lbs/mmbtu)	Potential Emitted NOx (tpd)	Proposed Emission Rate	Proposed Potential NOx (tpd)	Potential Reduction (tpd)	Percent Reduction
Distillate Fired Boiler	100 mmbtu/hr	0.23	0.15	0.09	0.07	0.09	61%
Gas Fired Boiler	100 mmbtu/hr	0.20	0.13	0.05	0.03	0.10	75%
Natural Gas Fired Process Heaters, Furnaces, etc	100 mmbtu/hr	0.20	0.14	0.10	0.07	0.07	50%
Asphalt Plants	150 mmbtu/hr	0.29	0.28	0.15	0.15	0.13	48%
Combustion Turbines	25 MW	0.40	0.66	0.14	0.23	0.43	65%
IC Engines	1000 hp	12 gr/bhp	0.16	6.9 gr/bhp	0.09	0.07	43%

Assume 55% capacity utilization

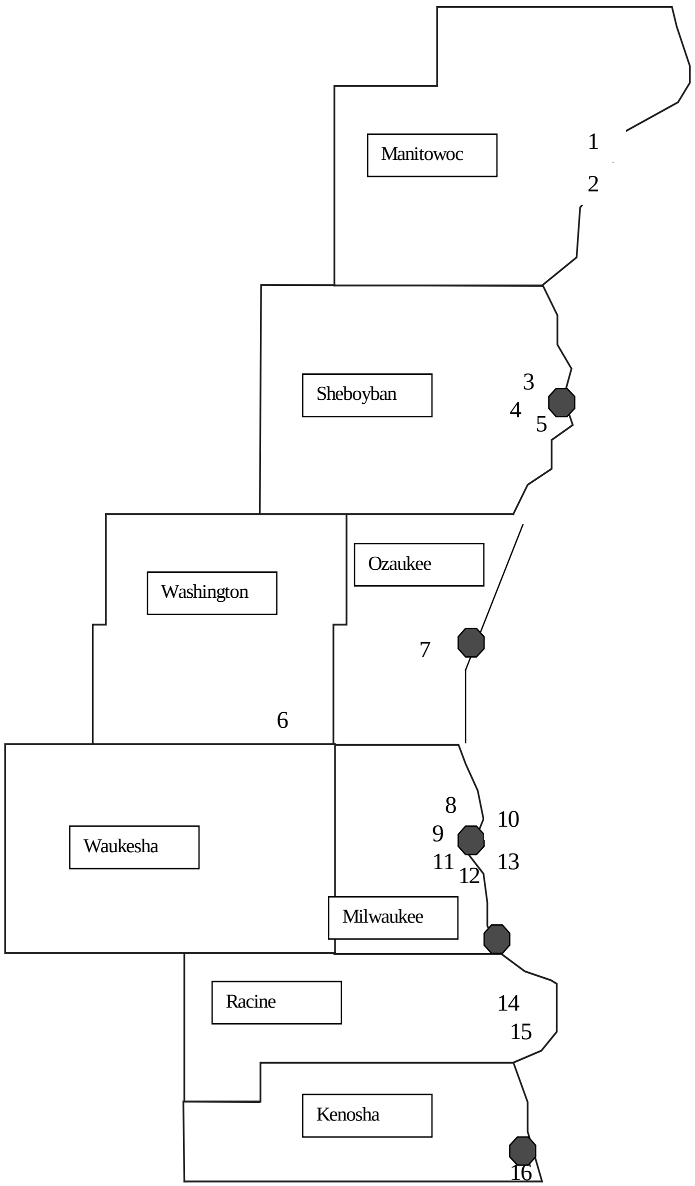
NOx Program Compliance

Any new or existing unit subject to a NOx emission limit performance standard must demonstrate compliance based on Part 60 monitoring or equivalent. The rule provides for a showing of alternative monitoring that is sufficient for an emission limit determination. Utility units equal to or greater than 500 mmbtu/hr, and subject to Part 75 monitoring, are excluded from the alternate monitoring. The rule provides for emission limit averaging by fuel, averaging between units, and trading. All units affected by emission limit performance standards must demonstrate compliance on a 30 day rolling average. A common averaging time provides program consistency and allows for such compliance options as unit averaging and trading.

Unit Averaging of Emission Rates – Emission rate averaging is provided for on a heat input weighted basis between units owned or operated by a single corporate entity subject to an proposed emission limit of NR 428. This includes averaging between and within new and existing sources including those units affected by electric utility corporate emission rates and specific emission rates. The program ultimately requires that a new source must first meet its applicable emission limit before averaging with another new or existing source. This is consistent with other new source programs which do not allow over control of an existing source to allow a new unit to come in at a higher limit. Any unit participating in averaging between units is required to utilize Part 60 monitoring to demonstrate compliance.

Trading – The rule provides for trading between corporate entities for any unit subject to a proposed emission limit. Trades can occur between any new or existing units under the program but, as with “Unit Averaging” all new sources must meet applicable emission limits before the trade. The source must also demonstrate the traded emissions are reductions below their 2000 base year emissions. Units participating in trading must demonstrate surplus and quantifiable emissions using Part 60 monitoring and Part 75 flow monitoring to demonstrate tradable mass emissions.

Figure 4-1. Facilities Identified to be Potentially Affected by NR 428



Utility Facility with Boilers > 500 mmbtu/hr

Edgewater
Port Washington
Valley
Oak Creek

Key	Facility
1	Manitowoc Public Utility
2	Rockwell Lime
3	Kohler
4	Plastics Engineering
5	ANR Pipeline
6	WEPCO - Germantown
7	Charter Steel
8	DOA / UW Milwaukee
9	Mid-American Drum
10	Miller Brewing Company
11	Milwaukee Co Power Plant
12	Pfister and Vogel Leather
13	Wisconsin Paperboard
14	Ball & Foster Glass
15	Case Corporation
16	WEPCO - Paris

Table 4-5 Electric Utility Boilers Affected and Projected Compliance in 2002 (Boilers => 500 mmbtu/hr)

Electric Utility System	Facility	County	Unit	2002 Facility NOx (tpd)	2002 Utility NOx (tpd)	Assumed Aditional Control Technology	Estimated System Annual Cost (Million$)	Estimated System Cost ($/ton)
Alliant	Edgewater	Sheboygan	Edge 5	10	43		< 1.6 M$	400
			Edge 4	27		Overfire Air / SNCR		
			Edge 3	5		Overfire Air		
WEPCO	Oak Creek	Milwaukee	OC 8	8	104	Low NOx Burners	up to 6.5 M$	1,300
			OC 7	9		Low NOx Burners		
			OC 6	9				
			OC 5	8				
	Pleasant Prairie	Kenosha	PP 1	27		*One SCR and LNB @ PP or LNBs @ PP and multiple LNB on other Units*		
			PP 2	25				
	Port Washington	Ozaukee	PW 3	2				
			PW 1	2				
			PW 2	3				
			PW 4	2				
	Valley	Milwaukee	Val 2	3				
			Val 2	3				
			Val 1	2				
			Val 1	2				
Total	**5 facilities**		**17 units**	**147**	**147**		**up to 8.1 M$**	**950**

Table 4-6 Identified Facilities Potentially Affected by Unit Specific Performance Standards for Existing Sources

Key	County	Source	Device	Current Emission Rate (lbs/mmbtu)	Regulatory Threshold	Proposed Requirement (lbs/mmbtu)	Anticipated Additional Control	2002 Esitmated Reduction (tons/day)
1	Manitowoc	Manitowoc Public Utility	Coal Stoker Boiler	0.54	75 mmbtu/hr	Optimization	Combustion Monitoring	0.34
			Coal Stoker Boiler	0.53	75 mmbtu/hr	Optimization	Combustion Monitoring	0.29
			Coal Stoker Boiler	0.53	75 mmbtu/hr	Optimization	Combustion Monitoring	0.21
			Coal Fluidized Boiler	0.11	100 mmbtu/hr	0.20		-
2		Rockwell Lime	Lime Kiln	0.14	75 mmbtu/hr	Optimization	Combustion Monitoring	0.06
3	Sheboygan	Kohler	Natural Gas Boiler	0.14	75 mmbtu/hr	Optimization	Combustion Monitoring	0.01
4		Plastics Engineering	Natural Gas Boiler	0.14	75 mmbtu/hr	Optimization	Combustion Monitoring	0.01
5		ANR Pipeline	IC Engine	1.8 gr/hp	2000 hp	6.0 gr/hp		-
6	Washington	WEPCO – Germantown	Combustion Turbine	0.72	50 MW	0.14	LNB (already installing)	0.09
			Combustion Turbine	0.72	50 MW	0.14	LNB (already installing)	0.05
			Combustion Turbine	0.72	50 MW	0.14	LNB (already installing)	0.03
			Combustion Turbine	0.72	50 MW	0.14	LNB (already installing)	0.10
7	Ozaukee	Charter Steel	Metal Working Furnace	0.14	100 mmbtu/hr	0.10	Low NOx Burner	0.03
8	Milwaukee	DOA / UW Milwaukee	Natural Gas Boiler	0.14	75 mmbtu/hr	Optimization	Combustion Monitoring	0.01
9		Mid-American Drum	Metal Working Furnace	1.5	100 mmbtu/hr	0.10	Low NOx Burner	1.23
10		Miller Brewing Company	Natural Gas Boiler	0.42	100 mmbtu/hr	0.10	Low NOx Burner	0.12
			Natural Gas Boiler	0.42	100 mmbtu/hr	0.10	Low NOx Burner	0.12
			Natural Gas Boiler	0.42	75 mmbtu/hr	Optimization	Low NOx Burner	0.12
			Natural Gas Boiler	0.42	75 mmbtu/hr	Optimization	Low NOx Burner	0.12
11		Milwaukee Co Power Plant	Coal Stoker Boiler	0.54	75 mmbtu/hr	Optimization	Combustion Monitoring	0.18
			Coal Stoker Boiler	0.54	75 mmbtu/hr	Optimization	Combustion Monitoring	0.17
			Coal Stoker Boiler	0.54	75 mmbtu/hr	Optimization	Combustion Monitoring	0.16
12		Pfister and Vogel Leather	Natural Gas Boiler	0.14	75 mmbtu/hr	Optimization	Combustion Monitoring	0.01
13		Wisconsin Paperboard	Natural Gas Boiler	0.35	100 mmbtu/hr	0.10	Low NOx Burner	0.37
14	Racine	Ball & Foster Glass	Glass Furnace	0.93	75 mmbtu/hr	Optimization	Combustion Monitoring	0.23
			Glass Furnace	0.93	75 mmbtu/hr	Optimization	Combustion Monitoring	0.58
15		Case Corporation	Natural Gas Boiler	0.14	75 mmbtu/hr	Optimization	Combustion Monitoring	0.01
16	Kenosha	WEPCO – Paris	Combustion Turbine	0.08	50 MW	0.09		-
			Combustion Turbine	0.08	50 MW	0.09		-
			Combustion Turbine	0.08	50 MW	0.09		-
			Combustion Turbine	0.08	50 MW	0.09		-
	Total	16 Facilities	31 units					4.7

Table 4-7 NR 428 Performance Standards for Existing Sources

Source Category	Applicable Threshold (equal to or greater)	Limitation	Monitoring Requirement
Seasonal Electric Utility System Average Emission Rate			
Electric Utility Boilers	500 mmbtu/hr	2002................0.33 lbs/mmbtu 2003.................0.31 lbs/mmbtu 2004................0.30 lbs/mmbtu 2005................0.29 lbs/mmbtu 2006................0.29 lbs/mmbtu 2007.................0.28 lbs/mmbtu	Part 75 CEM
Seasonal Emission Limit Requirements (Sources operating < 25 Capacity Factor Exempt)			
Cyclone	100 mmbtu/hr	0.45 lbs/mmbtu	Part 60 or equivalent
Fluidized Bed	100 mmbtu/hr	0.20 lbs/mmbtu	Part 60 or equivalent
Pulverized Coal	100 mmbtu/hr	0.30 lbs/mmbtu	Part 60 or equivalent
Gas Fired Boiler	100 mmbtu/hr	0.10 lbs/mmbtu	Part 60 or equivalent
Oil Fired Boiler	100 mmbtu/hr	Distillate..........0.12 lbs/mmbtu Residual...........0.20 lbs/mmbtu	Part 60 or equivalent
Metal Reheat, Annealing, and Galvanizing Furnaces	100 mmbtu/hr	0.10 lbs/mmbtu	Part 60 or equivalent
Combustion Turbine (No C.F. exemption)	50 MW	Gas: 75 ppm Oil: 110 ppm	Part 60 or equivalent
Reciprocating Engine (No C.F. exemption)	2000 hp	Rich burn ....9.5 gr/bhp Lean burn...........10.0 gr/bhp Distillate fuel.......8.5 gr/bhp Dual fuel.............6.0 gr/bhp	Part 60 or equivalent
Optimization of External Combustion Sources (Capacity Factor < 20% Exempt)*			
Solid Fuel Boilers	75 mmbtu/hr	Combustion Optimization	Continuous Combustion Analyzer
Gas/Oil Fired	75 mmbtu/hr	Combustion Optimization	Continuous Combustion Analyzer
Cement, Lime Kilns, Calciners	75 mmbtu/hr	Combustion Optimization	Continuous Combustion Analyzer
Reheat, Annealing, Galvanizing Furnaces	75 mmbtu/hr	Combustion Optimization	Continuous Combustion Analyzer
Glass Furnaces	75 mmbtu/hr	Combustion Optimization	Continuous Combustion Analyzer

* Includes all sources above this threshold not subject to an emission rate limit
Footnote – All emission limits are an ozone season requirement and based on a 30 day rolling average.

Table 4-8 NR 428 Performance Standards for New Sources

Source Category	Applicable Threshold (equal to or greater unless specified)	Requirement	Monitoring
Solid Fuel Fired Boilers	250 mmbtu/hr	0.15 lbs/mmbtu	Part 60 or equivalent
Solid Fuel Fired Boilers	< 250 mmbtu/hr	0.20 lbs/mmbtu	Part 60 or equivalent
Gaseous / Oil Fired Boilers	25 mmbtu/hr	Gas................ 0.05 lbs/mmbtu Distillate.........0.09 lbs/mmbtu Residual..........0.15 lbs/mmbtu	Part 60 or equivalent
Recovery Boilers	50 mmbtu/hr	0.10 lbs/mmbtu	Part 60 or equivalent
Cement Kilns, Lime Kilns, and Calciners	50 mmbtu/hr	Gas.................0.10 lbs/mmbtu Distillate.........0.12 lbs/mmbtu Residual...........0.20 lbs/mmbtu Solid Fuel........0.60 lbs/mmbtu	Part 60 or equivalent
Reheat, Annealing, Galvanizing Furnaces	50 mmbtu/hr	0.10 lbs/mmbtu	Part 60 or equivalent
Glass Furnaces	50 mmbtu/hr	4 lbs/ ton pulled glass	Part 60 or equivalent
Asphalt Plants	50 mmbtu/hr	Gas..................0.15 lbs/mmbtu Distillate..........0.20 lbs/mmbtu Residual or Waste Oil......... 0.27 lbs/mmbtu	Part 60 or equivalent
Process Heating Units (Process Heaters, Ovens, Dryers, and other external combustion)	50 mmbtu/hr	Gas...................0.10 lbs/mmbtu Oil.....................0.12 lbs/mmbtu	Part 60 or equivalent
Combustion Turbine	85 MW	Gas............. 12 ppmdv (15% O_2) Oil............... 25 ppmdv (15% O_2)	Part 60 or equivalent
Combustion Turbine	40 to 84 MW	Gas................ 9 ppmdv (15% O_2) Oil............... 25 ppmdv (15% O_2)	Part 60 or equivalent
Combustion Turbine	< 40 MW	Gas..............25 ppmdv (15% O_2) Oil................65 ppmdv (15% O_2)	Part 60 or equivalent
Combined Cycle Turbines	25 MW	Gas............... 3 ppmdv (15% O_2) Oil................ 8 ppmdv (15% O_2)	Part 60 or equivalent
Combined Cycle Turbine	< 25MW	Gas............ 14 ppmdv (15% O_2) Oil................25 ppmdv (15% O_2)	Part 60 or equivalent
Reciprocating Engines	1000 hp	Compression..........6.9 gram/bhp Spark Ignition.........4.0 gram/bhp	Part 60 or equivalent

Footnote - Performance standards do not supersede existing NSR or PSD program requirements.
Footnote – All emission limits are an annual requirement and based on a 30 day rolling average.